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The role of CCS in power systems with high levels of renewables penetration

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Abstract

Past studies have used power plant dispatch models with fixed plant portfolios to demonstrate that flexible capture systems may allow operators to increase profits in current electricity markets by increasing plant output at times of high demand. Some of these studies have also speculated that flexible capture systems may be valuable in future electricity systems with high shares of renewable energy as they could allow fossil fuel plants with capture to rapidly respond to changes in residual load. However, few studies have actually examined the role that plants with flexible capture could play in future power systems. Thus, this study examines the role that power generation with flexible capture systems could play in a future European power system where 80% of generation (by energy) is supplied by renewables. The results show that conventional base- and mid-load capacity decreases while the peak-load capacity (i.e., open cycle gas turbines) increases. In European regions with high shares of renewables, the residual load duration curve become steeper, and hourly changes in residual load increase significantly and happen more frequently at low load levels. The shift towards peak capacity and general decrease in load factors places technologies with high capital costs at a relative disadvantage. In the scenario in which CO_2 prices reach €50 per tonne CO_2 in 2050, approximately one-fifth of the CCS capacity deployed is equipped with flexible capture. However, in a scenario in which CO_2 prices reach €100 per tonne CO_2 in 2050, very little capacity is equipped with flexible capture systems as the cost of emitting CO_2 offsets the value of flexibility.

Keywords: Carbon capture; renewables; integration; European electricity markets

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1. Introduction

The share of electricity from renewable resources has been growing rapidly and the growth is likely to continue to increase in the short- to medium-term, driven by various support financial support mechanisms (e.g. feed-in tariffs, renewable energy certificates) and supportive market frameworks [1]. Over the longer term, a desire to make large emissions reductions may continue to drive renewable deployment. For example, in the Energy Technology Perspectives (ETP) 2°C Scenario (2DS), renewables grow to provide 57% of net global generation by 2050 from just under 20% today [2]. However, the integration of variable renewable energy into today's electricity transmission and distribution systems poses challenges [3]. One requirement for integrating variable renewables in a secure and cost-efficient manner is that flexibility options (e.g. generation with rapid ramp rates, energy storage, and demand side response options) must be incorporated into the electricity grid.

Past studies have examined technology options for flexible carbon capture and storage (CCS) from fossil-fuelled power plants [4-7] and their value in current electricity markets using plant dispatch models and historical loads or prices [8-13]. However, these studies have not examined the role that plants with flexible CCS could play in future power systems with high shares of renewable generation. The goal of this study is to examine the role that power generation with flexible CCS could play in a future European power market, where 80% of generation (by energy) is supplied by renewable electricity generation.

To assess the role of fossil fuelled power plants with flexible CCS, this study quantifies the installed capacity of power generation assets, storage and demand side response resources, the share of fossil power generation equipped with flexible CCS, and the load factors for each technology in Europe under two different CO_2 price scenarios.

2. Model

In this work a coupled investment and dispatch model (DIMENSION) is used to determine the minimal cost development of the European electricity system between 2020 and 2050. These results are supplemented by a detailed European dispatch model (DIANA) for 8760 hours in select years. Both models are developed by the Institute of Energy Economics at the University of Cologne (EWI).

The DIMENSION model uses a comprehensive, current database that covers all power plants and electricity storage facilities in 27 European countries, along with assumptions on electricity demand, technology parameters, renewable energy potentials and generation profiles to calculate the minimal cost development of the European electricity system [14]. The model allows investment conventional and renewable electricity generation capacity, energy storage, and demand-side management. Electricity generation options include fossil fuel (i.e., hard coal, lignite, and gas) power generation capacity with or without CCS and combined heat and power (CHP); nuclear power generation capacity; and, renewable generation capacity (i.e., biomass, hot-dry rock and conventional geothermal, solar concentrating power, solar photovoltaic, on- and off-shore wind, and run-of-river hydropower). Energy storage options include compressed air energy storage (CAES) and pumped and reservoir hydroelectric storage (although investment into the latter two types of storage is limited due to geographical constraints). The model considers 28 demand side management (DSM) options across six different sectors.

For this study, 13 model regions are considered (Figure 1). The model calculates the cost-minimizing generation mix for each region in 10 year time steps until 2050. At each time step, generation must match demand on 12 representative days, accounting for seasonal changes. To generate high resolution information on plant dispatch, the DIANA model is used to calculate the least-cost wholesale and balancing market dispatch for conventional generation capacity for each of the 8760 hours of the year in 2020, 2030, 2040 and 2050 in each region.

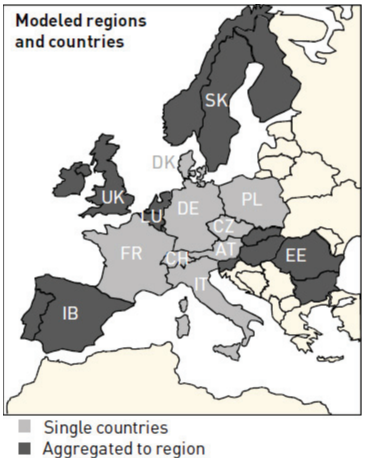

Figure 1. The countries and regions modeled in this study.

3. Assumptions

Final annual electricity demand in each modeled year for each of the 13 model regions are provided in Appendix A.1. The economic and technical parameters of generation and storage technologies in the model are based on studies by Prognos\EWI\GWS [15], IEA [16, 17], EWI [18], DLR [19], and IFEU [20]. The specific technical characteristics and overnight capital costs of power generation capacity, including those with CCS and incorporating a flexible capture system, are provided in Appendices A.2. and A.3. Power plants with flexible capture systems are assumed to be able to rapidly (i.e., within 15 minutes) deactivate the capture system, increasing the net plant generating capacity and CO_2 emissions rate to output to the equivalent of a plant without capture installed. This assumption is consistent with other studies in the literature [6, 10, 11]. All CO_2 capture systems are assumed to capture 85% of emissions from the power plant. Deployment of CCS technologies on fossil fueled generation is exogenously specified until 2030, at which time CCS is assumed to be a commercially available option in the model.

Fuel prices are consistent with those in the IEA World Energy Outlook 2010 [16], and are provided in Appendix A.4. Two scenarios are assumed for the evolution of European CO_2 prices to which emissions from power generation are subject. In Scenario A, emissions prices ramp linearly to reach €50 (2010) per tonne CO_2 in 2050; in Scenario B, CO_2 prices reach €100 (2010) per tonne. Table 1 provides the assumed emissions prices in each decade.

Table 1. Assumed CO_2 price scenarios, where prices are given in € (2010) per tonne CO_2.

Scenario	2020	2030	2040	2050
A	22.6	31.8	40.9	50
B	35.1	56.8	78.4	100

Future deployment of renewable generation capacity is exogenously specified in the model, although dispatch of this capacity is an endogenous decision. In 2020, approximately 700 GW of renewable capacity is deployed in the model, which increases to approximately 1,500 GW in 2050. The level of renewable capacity was chosen such that it supplies 80% of net electricity demand in 2050. For intermittent renewable energy technologies, region-specific generation profiles representing the maximum generation from each technology in each hour are based on historical resource data.

The European electric grid is assumed to be extended to include all of the Ten Year Network Development Plan projects by 2050 [21]. Given the stochastic nature of generation from intermittent renewables, an additional constraint was added that requires the system to hold balancing capacity of 10% of the combined solar and wind generation at all times.

4. Results

Under Scenario A, total generation capacity in Europe approximately doubles between 2020 and 2050 despite the total demand for electrical energy increasing by only approximately 25% and demand for CHP remaining approximately flat (Figure 2, left). The large growth in overall capacity is the result of the low secured capacity assumed for intermittent renewable generation. Despite the large growth in renewable capacity, growth in conventional thermal generating capacity remains flat between 2020 and 2050. However, there is a reduction in nuclear capacity and a growth in fossil fueled capacity, with the majority of the growth coming from gas fired generation. In addition, there is a reduction in coal fired generation with only a small amount of capture equipped coal fired capacity being constructed.

The higher CO_2 prices in Scenario B drive the construction of additional capture equipped coal and gas fired, as well as nuclear generation capacity, while decreasing the amount of gas and coal fired capacity without CCS (Figure 2, right). Under Scenario B, the total amount of capture equipped capacity is 80 GW, which grows to 94 GW in 2050.

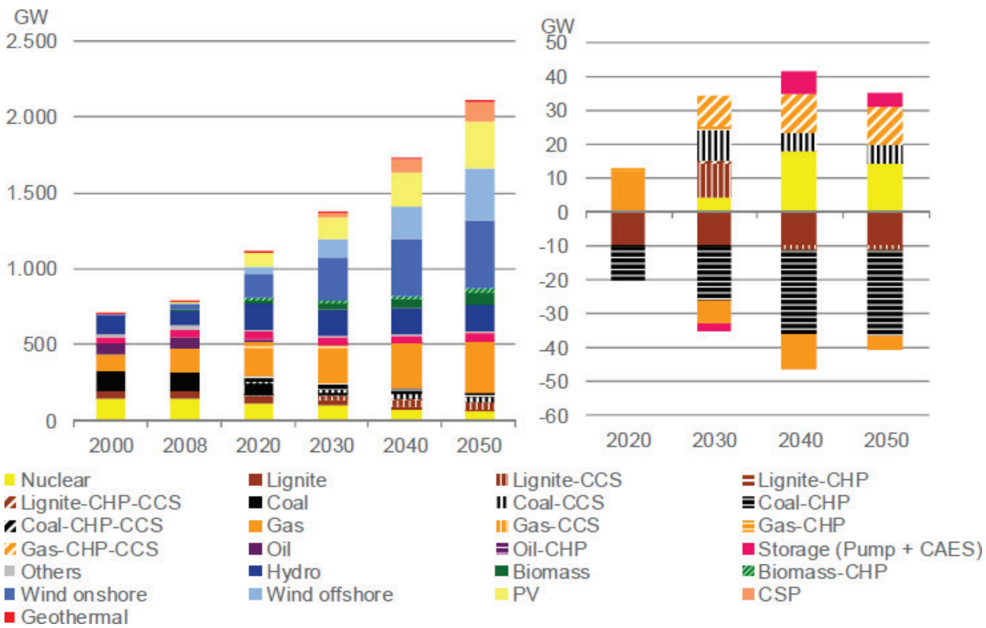

Figure 2. Gross generating capacity by technology in Scenario A (left) and the difference in capacity between Scenarios A and B (right) in 2020, 2030, 2040, and 2050. Generating capacities in 2000 and 2008 are historical values.

Given the large growth in renewable capacity and low marginal cost of generation from renewables, renewable generation grows by nearly a factor of three between 2020 and 2050 (Figure 3, right). By 2050, generation from renewables – the majority of which is from on- and off-shore wind – provides 75% of gross demand. Because the amount of conventional generation capacity is roughly constant between 2020 and 2050 in both Scenario A and B, the capacity factor of conventional generation decreases considerably. The higher CO_2 prices in Scenario B result in increased generation from capture-equipped fossil fuel capacity, nuclear, and biomass-fueled capacity (Figure 3, left).

The investments in renewable capacity and the CO_2 price reduce emissions in 2050 by nearly 70% relative to 1990 in Scenario A. Of the total emissions reductions in Scenario A, approximately 5% result from use of CCS on coal fired power plants and from 2020 onwards, approximately 20-30 $MtCO_2$ per year are captured and stored. However, the relatively low emissions prices in Scenario A result in continued growth in emissions from power generation through 2020, with the decline beginning between 2020 and 2030. The higher prices in Scenario B mean that emissions begin to decline sooner, and are ultimately reduced by over 90% relative to 1990.

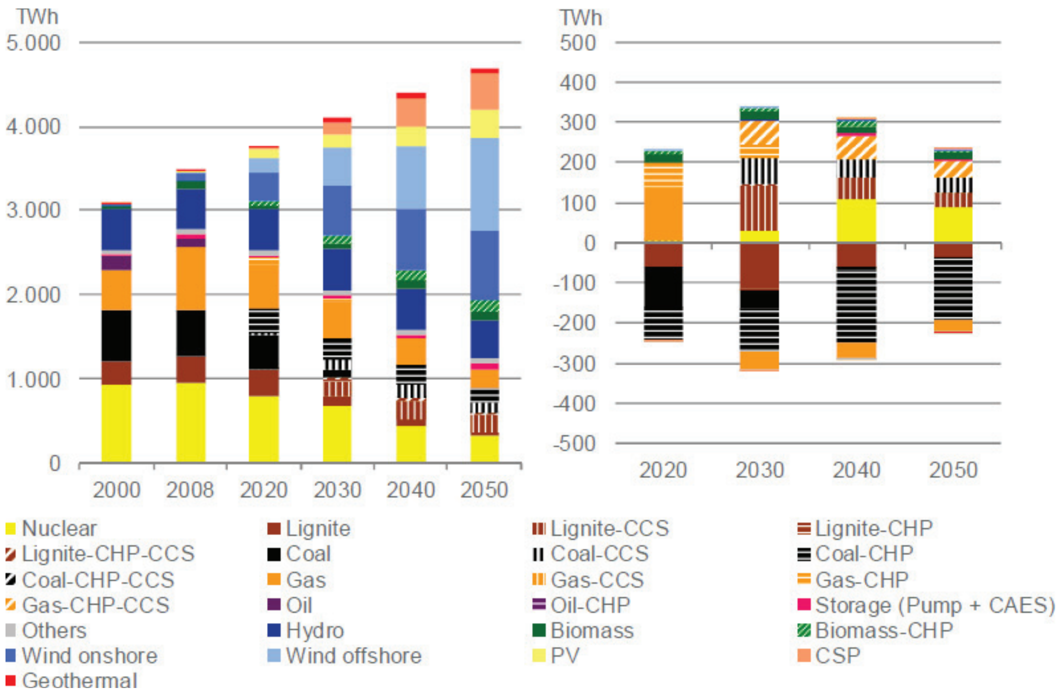

Figure 3. Gross generation by technology in Scenario A (left) and the difference in generation between Scenarios A and B (right) in 2020, 2030, 2040, and 2050. Generation in 2000 and 2008 are historical values.

Over the study period, the increased deployment of intermittent renewables results in increased volatility of residual load. The residual load is the electricity demand after subtracting potential renewable generation and is shown in Figure 4 for Germany in 2020 and 2050. While the shape of the residual load curve varies by region due to the different characteristics of the load and renewable capacity in each region, the slope of the curve increases between 2020 and 2050 for all regions with a high share of renewables. In the case of Germany, not only does the curve become steeper, but during several hundred hours of the year, there is negative residual load (i.e., during these hours there is more energy available from renewables than there is demand). In addition, the number hours with extreme changes in residual load (e.g., +/− 20 GW in the case of Germany) increases. The increase in the number of hours with negative residual load and extreme changes in residual load increases for many of the modeled regions. This requires rapid changes to the dispatch of conventional power plants, use of storage technologies, and adjustments to imports (or exports) in order to balance supply and demand.

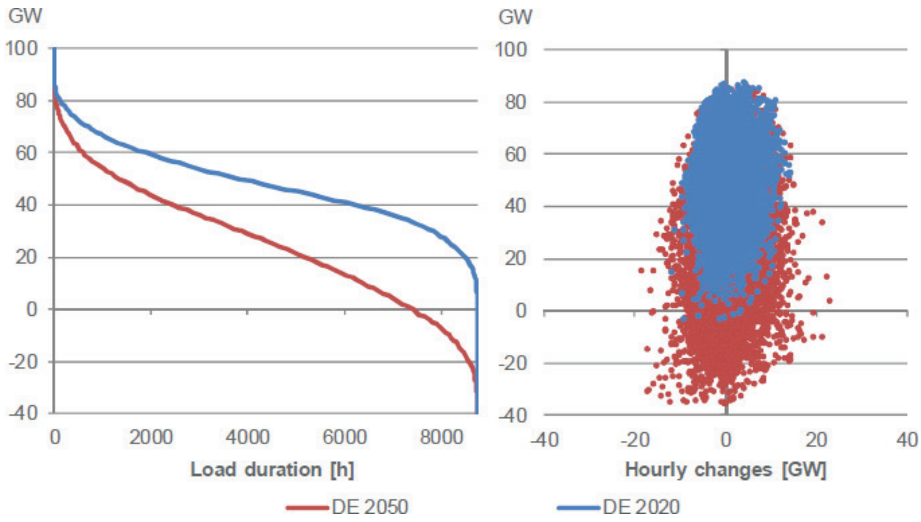

Figure 4. Residual load curve (left) and hourly changes in residual load (right) for Germany in 2020 (blue) and 2050 (red).

The increased need for short-term flexibility in conventional generation is met over the long run primarily by the construction of open cycle gas turbines in both scenarios. However, slightly less than one-fifth of fossil fuel capacity is equipped with flexible capture units in Scenario A (Table 2). Most of the capacity equipped with flexible capture is located in Poland, Germany, and the Czech Republic. In Scenario B, CO_2 prices are high enough that shut-down of a capture unit is uneconomical, and thus relatively little capacity is installed with flexible capture units.

Table 2. The gross capacity of conventional generation, capture-equipped conventional generation, and the percent of capture-equipped generation that is flexible (i.e., can bypass the capture system) in 2020, 2040, and 2050.

	2020		2040		2050	
	Total conv. (GW)	GW CCS (% flexible)	Total conv. (GW)	GW CCS (% flexible)	Total conv. (GW)	GW CCS (% flexible)
Scenario A	494.5	51.1 (14)	500.5	78.4 (19)	509.2	78.4 (19)
Scenario B	479.5	80.5 (0)	489.7	93.5 (2)	500.4	93.5 (2)

To illustrate the capability of flexible CCS units, Figure 5 depicts the dispatch realization in Poland during a December week in 2030 in Scenario A. Lignite-fueled power plants equipped with flexible capture units increase their output by bypassing the capture unit on Monday, Wednesday and Sunday afternoon to cope with low wind generation. In 2030 in Poland, fossil-fueled capacity usually runs with an operating capture plant but capture units are bypassed in about 260 hours of the year. While the value of flexibility increases over time due to the increasing share of renewable generation, increasing CO_2 prices and use of demand side management means that the power plants with flexible capture systems operate fewer hours each year with the capture system bypassed. For the example of Poland, plants with flexible capture systems run 196 hours in 2040 and 143 hours in 2050 with the capture systems bypassed.

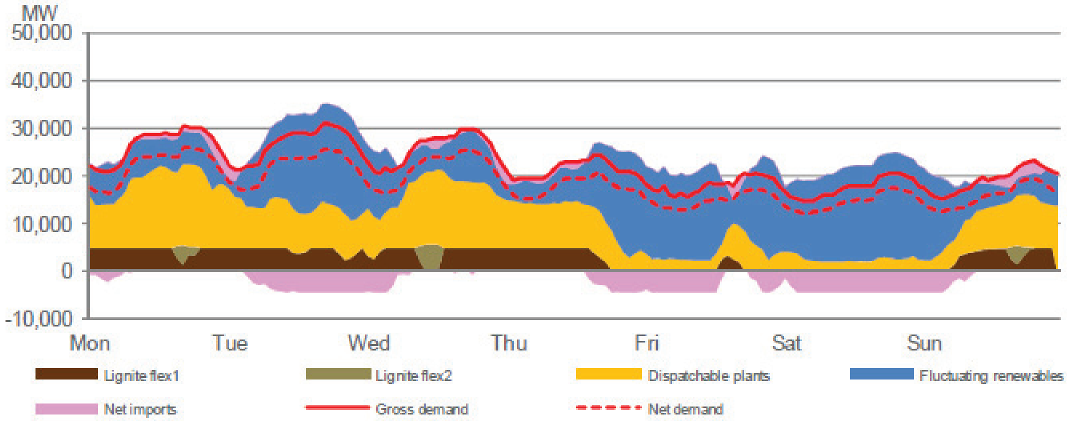

Figure 5. Dispatch of generation capacity during a December week in Poland in 2030

5. Conclusions

The results of the modeling show that increasing penetrations of renewable generation tend to increase the slope of the residual load curve, thereby reducing generation from base- and mid-load capacity. At the same time, the need for flexibility in the system to respond to rapid changes in the residual load – driven by variability of renewables – requires an increase in the peak load capacity. In both CO_2 price scenarios, open cycle gas turbines were the most cost-effective means of meeting the need for flexibility. Nonetheless, in the low CO_2 price scenario, about 15 GW of fossil fueled generation capacity with flexible capture units is constructed, the majority of which is located in Poland, the Czech Republic, and Germany. Despite the increasing value of flexibility in the system with time, increasing CO_2 prices make bypassing of the capture unit less attractive. In the high CO_2 price scenario, relatively little (i.e., less than 2GW) of capacity equipped with flexible CCS is constructed.

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Appendix A. Model Assumptions

A.1. Final electricity demand and potential heat generation in CHP

	2020		2030		2040		2050	
Region	Elec. (TWh_e)	CHP (TWh_{th})	Elec. (TWh_e)	CHP (TWh_{th})	Elec. (TWh_e)	CHP (TWh_{th})	Elec. (TWh_e)	CHP (TWh_{th})
Austria (AT)	65.3	(41.2)	70.0	(41.5)	74.3	(41.8)	78.5	(42.0)
BeNeLux (LU)	221.6	(129.9)	237.6	(130.8)	252.2	(131.5)	266.5	(132.3)
Czech Republic (CZ)	69.9	(55.1)	78.8	(55.7)	88.3	(56.4)	98.5	(57.0)
Denmark (DK)	40.5	(54.7)	43.4	(55.1)	46.0	(55.4)	48.6	(55.7)
Eastern Europe (EE)	151.9	(132.6)	171.1	(134.2)	191.8	(135.7)	214.0	(137.2)
France (FR)	480.0	(31.6)	514.6	(31.8)	546.4	(32.0)	577.2	(32.2)

Germany (DE)	567.0	(192.4)	584.2	(192.9)	584.2	(192.9)	584.2	(192.9)
Iberian Peninsula (IB)	354.5	(72.9)	409.4	(73.9)	470.5	(75.0)	538.0	(76.0)
Italy (IT)	362.9	(169.2)	419.1	(171.7)	481.6	(174.1)	550.7	(176.5)
Poland (PL)	140.0	(93.3)	157.8	(94.4)	176.9	(95.5)	197.3	(96.6)
United Kingdom (UK)	415.5	(68.1)	445.6	(68.6)	473.0	(69.0)	499.7	(69.3)
Scandinavia (SK)	365.4	(98.1)	391.8	(98.8)	415.9	(99.4)	439.4	(99.9)
Switzerland (CH)	65.4	(3.0)	70.1	(3.0)	74.5	(3.0)	78.7	(3.0)

A.2. Technical performance characteristics of conventional power generation options

Technology	LHV efficiency (%)	Availability (%)	Fixed O&M costs (€/kWa)	Lifetime (y)	Minimum load (%)	Ramp-up times (h)	Net efficiency (%)
Nuclear	33.0	84.5	96.6	60	45	48	33.0
Lignite	43.0	86.3	43.1	45	30	3-12	43.0
Lignite CHP	22.5	86.3	62.1	45	30	3-12	22.5
Lignite CCS	33.5	86.3	70.3	45	30	3-12	33.5
Lignite *flex*-CCS	32.9	86.3	71.6	45	30	3-12	32.9
Lignite – *innv*	46.5	86.3	43.1	45	30	3-12	46.5
Lignite – *innv* CCS	37.0	86.3	70.3	45	30	3-12	37.0
Lignite – *innv flex*-CCS	36.4	86.3	71.6	45	30	3-12	36.4
Lignite – *innv* CHP-CCS	20.0	86.3	89.3	45	30	3-12	20.0
Hard coal	46.0	83.8	36.1	45	30	1-6	46.0
Hard coal CHP	22.5	83.8	55.1	45	30	1-6	22.5
Hard coal CCS	36.5	83.8	59	45	30	1-6	36.5
Hard coal *flex*-CCS	35.9	83.8	60.2	45	30	1-6	35.9
Hard coal – *innv*	50.0	83.8	36.1	45	30	1-6	50.0
Hard coal – *innv* CCS	40.5	83.8	59	45	30 1-6		40.5
Hard coal – *innv flex*-CCS	39.9	83.8	60.2	45	30	1-6	39.9
Hard coal – *innv* CHP-CCS	20	83.8	78	45	30	1-6	20
CCGT	60.0	84.5	28.2	30	40	0.75-3	60.0
CCGT – CHP	36.0	84.5	40.0	30	40 0.75-3		36.0
CCGT – CCS	52.0	84.5	46	30	40	0.75-3	52.0
CCGT – *flex*-CCS	51.6	84.5	50.5	30	40	0.75-3	51.6
CCGT – CHP-CCS	33.0	84.5	57.9	30	40	0.75-3	33.0
OCGT	40.0	84.5	17.2	25	20	0.25	40.0

Notes: *Innv* is an abbreviation for plants using “innovative” technologies. In the case of hard coal plants, innovative plants have a main steam temperature of 700°C and pressure of 350 bar. In addition to these high pressures and temperatures, innovative lignite plants also use pre-drying technology. *Flex* is an abbreviation for “flexible” CCS systems, in which steam from the absorber reboiler can be diverted to the steam turbine to boost the both the plant output and emissions rate to the equivalent of a plant without capture.

A.3. Overnight capital cost of conventional power generation options in EUR (2010) per kW capacity

Technology	2020	2030	2040	2050
Nuclear	3,157	3,157	3,157	3,157
Lignite	1,850	1,850	1,850	1,850
Lignite CHP	2,350	2,350	2,350	2,350
Lignite CCS	-	2,896	2,721	2,652
Lignite *flex*-CCS	-	3,041	2,842	2,764
Lignite – *innv*	1,950	1,950	1,950	1,950
Lignite – *innv* CCS	-	2,996	2,821	2,752
Lignite – *innv flex*-CCS	-	3,145	2,945	2,867
Lignite – *innv* CHP-CCS	-	3,396	3,221	3,152
Hard coal	1,500	1,500	1,500	1,500
Hard coal CHP	2,650	2,342	2,135	2,030
Hard coal CCS	-	2,349	2,207	2,152
Hard coal *flex*-CCS	-	2,459	2,298	2,236
Hard coal – *innv*	2,250	1,904	1,736	1,650
Hard coal – *innv* CCS	-	2,753	2,443	2,302
Hard coal – *innv flex*-CCS	-	2,894	2,560	2,410
Hard coal – *innv* CHP-CCS	-	3,191	2,842	2,682
CCGT	700	700	700	700
CCGT – CHP	1,000	1,000	1,000	1,000
CCGT – CCS	-	1,127	1,057	1, 030
CCGT – *flex*-CCS	-	1,189	1,109	1,078
CCGT – CHP-CCS	-	1,409	1,341	1,314
OCGT	400	400	400	400

Notes: *Innv* is an abbreviation for plants using “innovative” technologies. In the case of hard coal plants, innovative plants have a main steam temperature of 700°C and pressure of 350 bar. In addition to these high pressures and temperatures, innovative lignite plants also use pre-drying technology. *Flex* is an abbreviation for “flexible” CCS systems, in which steam from the absorber reboiler can be diverted to the steam turbine to boost the both the plant output and emissions rate to the equivalent of a plant without capture.

A.4. Fuel prices (€/MWh_{th})

	2008	2020	2030	2040	2050
Uranium	3.6	3.3	3.3	3.3	3.3
Lignite	1.4	1.4	1.4	1.4	1.4

Hard coal	17.3	13.4	13.8	14.3	14.7
Oil	44.6	99.0	110.0	114.0	116.0
Natural gas	25.2	28.1	31.3	33.2	35.2
Hydrogen	-	46.7	47.4	48.2	48.9
Bioliquid	53.2 - 94.3	57.1 - 101.1	61.8 - 109.4	61.8 - 109.4	61.8 - 109.4
Biogas	0.1 - 70.0	0.1 - 67.2	0.1 - 72.9	0.1 - 78.8	0.1 - 85.1
Biosolid	15.0 - 27.7	15.7 - 34.9	16.7 - 35.1	17.7 - 35.5	18.8 - 37.5